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MESSAGE FROM CHASE ENERGY ECONOMICS

This special issue marks the beginning of a new policy regarding the Petroleum Situation. As in the past, we plan to use this publication as a forum for presenting our views on industry developments. From now on, however, publishing will be at irregular intervals as developments warrant. We think that this particular issue will be of wide interest to our readers and have accordingly expanded its normal size.

David J. Behling

THE CHANGING STRUCTURE OF THE U.S. NATURAL GAS INDUSTRY

INTRODUCTION

Over the past two years, natural gas prices have continued to increase despite growing amounts of shut-in supply and declining prices for competing oil products. This situation, in turn, has called into question the viability of the legal and regulatory system underlying production, transportation, distribution and end-use of natural gas. One of the key questions influencing the outlook of the industry is whether or not the industry will be able to market natural gas at prices competitive with distillate fuel oil in residential and commercial markets and with residual fuel oil in industrial and electric utility markets.

The current situation is a result of several past policy changes, the most important being the incentive pricing provisions of the 1978 National Gas Policy Act (NGPA), in addition to the recession of 1981-1982 and the simultaneous worldwide decreases of oil prices. The freedom to sell incentive gas at free-market prices permitted by the NGPA led to average wellhead price increases of a sufficient magnitude to bring the average price of natural gas to industrial customers up to the price of residual fuel oil and the average price to residential and commercial users close to the price for distillate fuel oil. As a result of these trends, the share of gas in industrial and utility markets dropped sharply, with a lesser decline occurring in residential and commercial markets. Furthermore, all industrial energy consumption, including that of natural gas, dropped drastically in the 1981-1982 recession.

On the supply side, the high incentive prices permitted by the NGPA initially led to large increases in gas drilling, reserves, and production capacity. These conditions of rising capacity and diminishing demand led to the current soft gas market.

However, the closing of previous gaps between natural gas prices and oil product prices in industrial and utility markets and the development of a natural gas surplus resulted in a major push for new competitive forces within the industry, initially coming from intrastate pipelines and brokers in combination with producers anxious to market their excess supplies. In the latter half of 1983, spot-market activity increased considerably as several interstate pipelines rapidly implemented their own spot market programs. The Federal regulatory response has been generally passive, with gradual and somewhat reluctant Federal Energy Regulatory Commission (FERC) approval of new spot market programs, but only as a channel for creating additional sales and not to penetrate traditional markets.

This article presents an analysis of the various ways in which the structure of the U.S. natural gas industry is changing and shows how different future structural evolutions might influence future demand, supply and pricing. As the Congressional policy debate concerning natural gas receives considerable press coverage, this aspect of the industry is not treated in detail here. The focus of this paper is on changes occurring in the industry rather than those which might occur in Washington. The key question asked is, under the more likely combinations of all the different potential institutional outcomes, how long will it take for excess supplies of natural gas to be worked off so that drilling can once again begin to increase.

ORGANIZATION OF THE U.S. NATURAL GAS INDUSTRY

The U.S. natural gas industry includes three distinct segments: producers, pipeline companies and distributors. Producers of natural gas, in turn, can be divided into three categories: (1) The 25 major companies, historically reviewed in the Chase annual study "Financial Analysis of a Group of Petroleum Companies" and are commonly known as the Chase Group; (2) The large independents, defined as the remainder of

the largest 120 U.S. oil and gas companies; and (3) the smaller independents, comprising the balance of the U.S. producers. In 1982, the Chase Group produced 41% of all natural gas in the U.S., the larger independents 18% and the smaller independents 41%. Over time, the share of the independents has been increasing at the expense of the Chase group of companies.

The line of distinction between producers and pipeline companies has become less clear as pipeline companies have developed their own natural gas exploration and production (E&P) activities. In 1982, some 11% of total U.S. natural gas production was accounted for by companies either owned by or affiliated with pipeline companies. The distribution of natural gas in the U.S. is performed by a variety of companies: combination gas and electric utilities, municipally-owned systems, utility subsidiaries of diversified companies and investor-owned gas distribution utilities. End users of natural gas are generally divided into four categories: residential, commercial, industrial and electric utility. Some large industrial users produce their own gas, but this is fairly insignificant.

The natural gas industry remains heavily regulated. Some key features of the present system include:

1. *Wellhead Price Controls* – As of 1978, Congress extended price controls in the NGPA to intrastate markets, in addition to interstate markets.

2. *Long-term Sales Contracts* The general practice of dedicating the production from a well or a field to one purchaser over the entire life of the well or field across from (1) Federal regulations requiring lifetime dedication of wells to interstate commerce and (2) Requirements for external financing of interstate and intrastate pipeline construction.

3. *City-gate Prices Based on Rolled-in Pipeline Gas Acquisition Costs plus Regulated Mark-Ups* – Interstate pipelines purchase gas directly from producers or from local intrastate pipeline gathering systems and are limited by FERC in the amount by which they can pass on average costs through prices they charge distribution companies.

4. *Distribution Companies as Sole Distributors of Gas to End Users* – All gas users, including large industrial users, are encouraged by FERC and state public utility commissions to purchase gas from distributors rather than directly from interstate pipelines. In intrastate markets, however, large industrial customers have always been permitted to purchase natural gas directly from intrastate pipelines.

5. *Cost-of-Service Utility Pricing by Distributors* – The rates that gas distribution utilities are permitted to charge different classes of customers depend primarily on two factors: fuel costs and fixed costs. Residential and commercial users generally purchase non-interruptible service and the rates they are charged incorporate a somewhat larger than proportional share of the fixed costs in addition to a fuel charge. Industrial and electric utility users, on the other hand, generally purchase interruptible service and therefore bear a less than proportional allocation of fixed costs.

Until recently, it was generally envisioned that all five of the above mainstays of the industry organization would persist with the exception that, under conditions of the NGPA, greater quantities of wellhead gas would shift toward those gas categories which are either currently deregulated (section 107 "high cost" gas) or scheduled for deregulation after 1984 ("new" gas).

Thus, while the NGPA did not allow for the deregulation of all gas, it did permit circumstances in which the average price of gas could rise. By June 1982, the price of decontrolled high-cost gas from deep reservoirs rose to $7.41 per thousand cubic feet, substantially above the market-clearing price—meaning, the price at which supply and demand would balance in an unimpeded market. In an attempt to secure these high-cost supplies for the long term which would (1) avoid customer commitment problems that had occurred during the mid-70's and (2) meet FERC rate-of-return criteria, many pipeline companies signed "take-or-pay" provisions with producers that obliged them to pay for gas even if it could not be marketed. As pipelines found themselves unable to sell all their gas, their "take-or-pay" provisions went into effect. Obliged to buy new and more expensive supplies, pipelines were often forced to cut back their purchases of less expensive gas, precisely the opposite of what would presumably occur in a competitive market. In the soft gas market, a considerable amount of low-cost gas became available but pipelines often could not buy it because of existing contracts locking them into more expensive purchases.

CURRENT DEMAND, SUPPLY AND PRICE CONDITIONS

After peaking at an annual rate of 20.0 TCF in the summer of 1981, the seasonally adjusted annual rate of gas deliveries declined to 16.5 TCF in January of 1983. Subsequently, though it appeared that a recovery had occurred, the annual rate then declined sharply, reaching a new low of 16.3 TCF in August. Since August, little recovery took place until the cold weather of December sharply increased deliveries. For the year 1983, gas deliveries equalled 16.9 TCF relative to 18.0 TCF in 1982. This continued weakness in natural gas demand is in contrast to the small but sustained recoveries occurring in the oil, coal and electricity markets in the U.S. in 1983.

Since mid-1981, both the industrial and electric utility natural gas markets have been particularly weak. Industrial natural gas demand in November of 1983 was down 25% from the mid-1981 peak rate and the November 1983 utility demand was down 21% from it's prior 1981 peak. However, particularly since October, industrial and utility demand for natural gas has picked up, primarily as a result of more competitive pricing in conjunction with an expanding economy.

PRICING

In all markets, gas has become far less competitive over the past three years. In the residential market, the gap between natural gas and heating oil prices narrowed from $4.26 per million BTU as of January of 1981 to $1.71 per million BTU in October of 1983, but then widened to $2.54 as of January of 1984. In the industrial market, the gap between interstate natural gas and residual fuel oil prices closed completely, before opening again to $0.51 per million BTU in January of 1984. While the gap between prices for natural gas and residual fuel oil in the electric utility market has not closed, this is only because, in this market, the average price of natural gas is defined to include large amounts of very low-priced intrastate gas on long-term contracts, many of which expire in the mid-1980's.

NATURAL GAS SUPPLY AND CREATION OF THE "BUBBLE"

While greater drilling resulting from the NGPA price incentives substantially increased additions to proven reserves and potential production, the falling demand previously discussed subsequently led to sharp declines. From 20.0 TCF in 1981, domestic production declined 17 percent to an estimated 16.6 TCF in 1983. At the same time, proven lower 48 reserves

increased 2 percent from 167 to 170 TCF between January 1, 1981 and January 1, 1983. The net result was increased amounts of gas being held in storage and increased amounts of shut-in gas. Since mid-1982, as this "bubble" of shut-in gas began to expand, both gas well drilling and well completions began dropping steeply.

The natural gas bubble refers to the resulting excess of supply over demand. It has been measured in a number of ways. First, through surveys of the amount of excess deliverability. Estimates of such deliverability, however, are susceptible to over-estimation due to greater pressure on financially-troubled industry participants to overstate reserves in an attempt to obtain more external financing. Producers also have an incentive to overstate reserves in order to obtain a greater amount of permitted deliverability from state regulatory bodies, such as the Texas Railroad Commission, who are prorating gas production. Further, the actual engineering methods used to estimate deliverability may yield deliverability estimates that cannot be sustained for any long period of time. Under the specified procedures, a well is completely shut for the 24 hours prior to measurement. Then, the measurement is of production for the next 24 hours with all valves completely open. On the other hand, current deliverability may be under-estimated as producers may delay hooking new wells into the pipeline gathering and distribution network, knowing that there is a good chance they will not immediately be able to sell any gas. On balance, however, it appears that most estimates of deliverability overestimate actual amounts available.

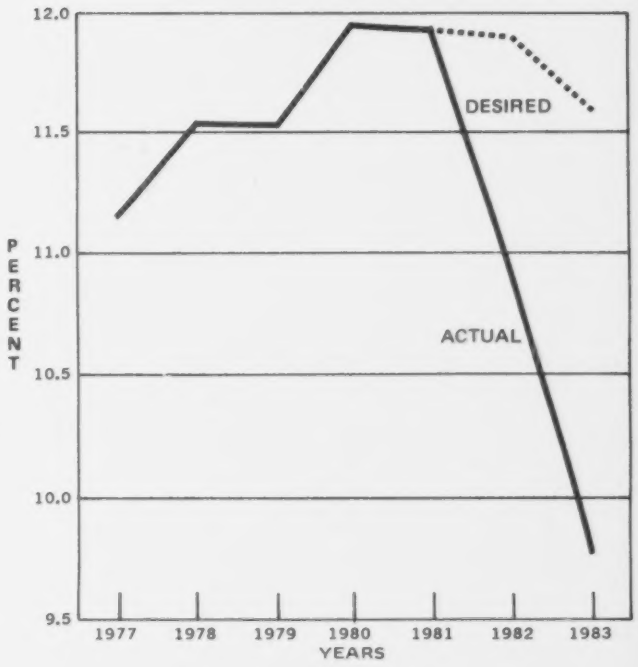
A far better method of estimating the size of the surplus is to compare actual production with "potential production", or capacity, defined as that amount which would be produced under "normal" circumstances. Potential production, in turn, can be defined as "produceability" multiplied by the amount of proven reserves, where produceability is the ratio of annual production to beginning or year reserves. Actual produceability is the actual percent of production to reserves, while "desired" produceability is that percent of reserves which producers would desire to produce, assuming that all production would be sold. Both actual and desired produceability are shown in Figure 1.

Actual produceability increased steadily to reach a peak of 12.0 percent in 1981 before declining to 10.9 percent in 1982 and an estimated 9.8 percent in 1983, due to lack of effective demand. Estimates of the "desired" rate of produceability for 1982 and 1983 are shown as the dotted line in Figure 1. A reduction in produceability would have occurred since 1981 even if demand had been sufficient to bring about full capacity levels of production. Less in-field drilling would have occurred as price increases moderated. Further, the collapse in deep gas would have also lowered desired produceability.

The level of reserves declined continuously from around 290 TCF as of January 1, 1967 to 181 at the beginning of 1977 and to 167 TCF in 1981. In 1981, reserves increased as a result of the upsurge in drilling stemming from NGPA price incentives and healthy increases in cash flow. Since then, they have leveled off and in all probability have begun to decline.

The amount of natural gas which is shut-in can be measured by multiplying the difference between actual and desired produceability by the amount of reserves. The resulting estimates of shut-in gas are 1.7 TCF for 1982 and 3.0 TCF for 1983. Further, during 1983 there was an average of about 0.2 TCF more gas in underground storage than normal, so that the size of the total 1983 bubble averaged about 3.2 TCF. However, by the end of 1983, the size of the bubble lowered

FIGURE 1
U.S. LOWER 48
PRODUCTION AS A PERCENT OF RESERVES
ACTUAL PRODUCEABILITY VS.
DESIRED PRODUCEABILITY



to about 2.9 TCF because the surplus amounts in storage had been worked off and production had increased.

In 1982, both in absolute size and percent of capacity, independents had the greatest amount of shut-in natural gas. The reason may have been that independents were bringing more capacity on line in areas not as easily hooked into the pipeline infrastructure as new capacity from the majors. In 1983, however, the pattern of holdings of shut-in gas changed completely, as the majors now have proportionately more shut-in capacity than independents. The reason for this shift is that major producers have been less willing to negotiate with interstate pipelines regarding minimum take-levels and prices as specified in previously-agreed-upon contracts. On the other hand, many small producers have been willing (or forced by circumstances) to grant lower prices in exchange for continued takes so to maintain at least some cash inflow.

CURRENT LEGAL, REGULATORY AND POLICY CONDITIONS

Many recent actions have been taken, without any change in the NGPA, in order to stimulate gas sales by reducing gas prices, particularly in the price-sensitive industrial markets. Many of these actions have been initiated by interstate pipelines in an attempt to impel producers and utilities to accept the new market realities on terms more favorable to the interstate pipelines. First, pipelines have invoked contract options called market-out clauses, which legally permit a pipeline to reduce its take levels and give the producer the right to sell his production to another party. Pipelines have exercised this option as a lever to reduce the contract price of gas, particularly from high-cost and high-price NGPA categories of gas. Prices of this high-cost deep gas have generally declined from a range of $7–$10/MCF to a current range of $3–$6/MCF.

Second, where legally possible, some pipelines have been reducing specified takes of higher-cost categories of gas in favor of lower-cost categories, thus lowering their system-wide

average cost of purchased gas. The taking of amounts of high-cost gas below amounts specified in take-or-pay contracts is now common practice, leading to much-publicized litigation, but no resolution, as the courts have been waiting to see whether Congress will act. Nevertheless, the general pattern has been a minimum of legal confrontation between pipelines and producers over take-or-pay contracts.

Third, while some interstate pipelines have sought rate increases in purchase gas adjustments (PGA's) from FERC, many pipelines feared that rate increases would lead to greater sales declines and instead sought interim rate declines.

Finally, some distributing utilities have gone to their state public service commissions and urged that they use market-based pricing criteria in setting rates.

SPOT MARKET PLAYERS

Some groups of producers, intrastate gas-gathering pipelines and interstate pipelines have begun to play the role of merchandiser, arranging for the sale of gas directly from producers to end users. A new group of independent marketers and brokers is also swarming into this new market. These independent marketers, also bound by the NGPA, usually do not own pipeline facilities but, in the course of facilitating transactions, they usually take title to the gas.

The emergence of independent brokers who directly match users with producers served as a catalyst for the development of interstate pipelines' spot market programs. Currently, the spot market activities of interstate pipelines are of the same general nature as those of the brokers. They permit a one-to-one matching of new spot market deliveries and of industrial purchases by customer. Like brokerage-arranged transactions, they may have the effect of substituting lower-priced spot-purchased gas for gas previously contracted. Thus, the current pipeline system can now be described as a system of voluntary for-hire carriage, with considerable political pressure coming from producers, brokers and large industrial users for Congress to make this voluntary system mandatory.

Industrial interest in and knowledge of these new spot market programs sponsored by brokers and interstate pipelines is growing and actual quantities of gas moving under such programs is increasing rapidly, although few hard numbers are yet available. The current size of the spot market is often put at 1 TCF, about 6% of all deliveries.

REGULATORY AND POLICY RESPONSE

FERC seems to recognize that greater pricing flexibility is needed to work off excess natural gas supplies. At the same time, they seem to wish to limit the roles of new programs and participants to creating *additional* sales, leaving traditional sales to the marketing channels of the old system. For the incentive programs of the interstate pipelines to be approved, the acquisition costs of the newly purchased incentive gas must be *greater* than the weighted average costs of its other purchases. Further, all the gas purchased for incentive sales programs must come from the take-or-pay pool of existing contracts and must be released from that pool. These restraints put interstate pipelines at a distinct competitive disadvantage relative to the brokers, thus increasing the incentive for pipelines to achieve take-or-pay relief from their supplies. FERC has been waiting to see if Congress will act, and, while Congress may, as we go to press, this appears unlikely. FERC has indicated that it will act if Congress doesn't. The new FERC commissioner has indicated that FERC is now studying problems in jurisdiction and procedure as well as the substantive issues and will release statements as to what FERC will handle. In the meantime, FERC will also have to rule on new certification and renewals of spot market programs. How they rule on these issues may halp to indicate whether FERC sees the growing spot market as a temporary tool to work off the bubble, or as a permanent change in the industry's structure. Should FERC decide in favor of a permanent spot market, the next question most likely will be whether or not a separate spot market program can be assembled for just industrial and utility natural gas users.

NATURAL GAS PRICE OUTLOOK

We assume that sufficient institutional changes will occur so that competition takes place between either alternative gas delivery systems, and/or between a regulated franchised gas delivery system and competing oil product fuels. Further, this competition will prevent natural gas prices from rising at the recent high rates over the next two years. We assume that natural gas prices, after taking appropriate quality differentials into account, will align themselves with the prices of competing alternative fuels. Achievement of this alignment will be helped by the structural changes described above and by the shift in distribution utility price regulation toward greater emphasis on competitive burner-tip pricing, as opposed to cost-of-service pricing. Under these conditions, gas prices increase one to two percentage points greater than the rate of inflation over the next 5 years.

The primary downside risk to this price forecast is that official OPEC prices may decline in 1984 due to another decrease in the Saudi marker price. However, we currently attach only a 5 to 10 percent probability to this outcome. But, if it does occur, resulting weakness in oil product prices will make needed natural gas price adjustments even more difficult, given the rigidities of the current regulatory system. A major upside risk comes from the possibility that expanded hostilities in the Middle East will lead to greater curtailments of oil production and/or shipments from the Middle East and higher oil product prices.

DEMAND OUTLOOK

In 1983, the total natural gas consumption of 16.95 TCF was approximately apportioned by end-use sector as follows: residential and commercial, 39%; industrial, 34%; electric utilities, 18%; and 9% transportation (primarily for pipeline fuel). Future gas consumption by sector is a product of future energy consumption by sector and of natural gas's share of each sector's total energy consumption. Transportation is not discussed because of its minimal demand for natural gas.

In 1983, growth in industrial energy consumption of all fuels and electricity has lagged considerably behind growth in all the relevant macroeconomic indicators. In a recovery period, growth in industrial energy consumption generally tends to lag growth in the economy due to inventory adjustments. Further, in the early part of 1983, manufacturers were able to increase output without purchasing energy by drawing down on the energy inventories they had accumulated.

Energy demand forecasts are shown in Table 1. In 1984, considerable growth in energy consumption is expected in all sectors relative to that which occurred in 1983.

TABLE 1

ENERGY GROWTH 1982-1990

(Average Annual Percent Change)

	83/82	84/83	85/84	90/85	MEMO 73/81
Energy Growth By Sector					
Residential/Commercial	−1.7	3.5	1.2	1.4	0.5
Industrial	1.8	7.0	2.5	1.2	− 1.0
Electric Utility	1.8	4.5	2.8	2.7	2.8

In the residential and commercial sector, greater growth in real GNP spurs increased growth in commercial energy usage. The large growth in 1984 residential and commercial energy consumption results from the colder weather experienced in the winter of 1983–84 relative to the very warm winter experienced in 1982–83.

The sharp 7% growth in industrial energy consumption in 1984 is a result of an estimated 8.5% growth in heavy energy-using industrial production, offset by some continuing industrial energy conservation. Electric utility energy consumption also grows most rapidly in 1984.

In 1985, growth in energy consumption in all sectors tapers off as a result of the slowdown in the growth in the economy. Over the 1985 to 1990 period, the annual trend rate of growth in both residential/commercial and industrial energy consumption exceeds the average annual growth exhibited in the 1973–81 period. This is because, relative to the 1973–81 period, slower increases in real energy prices will bring less efficiency improvements in the residential and commercial sector. Also greater recovery in the energy-intensive smokestack industries will lead to greater growth in industrial energy consumption.

By far the greatest uncertainty, on both the up and down sides, is the rate of growth in industrial energy consumption. This forecast is based on the presumption that energy-intensive industrial growth to 1985 will be large, but not nearly large enough to offset the dramatic plunge these industries took in the 1980–1982 period. Then, over the 1985–1990 period, real growth of these industries will slightly lag that of real GNP.

SHARE OF NATURAL GAS IN ENERGY CONSUMPTION

In general, natural gas's share of total energy consumption declined in all sectors from 1973 to the late 1970's, increased sharply for a year or two, and then declined again. Currently, the shares of natural gas are at their historical lows in all sectors. Through December of 1983, natural gas accounted for 27.8% of all residential and commercial energy consumption, 26.0% of all industrial consumption and 12.1% of energy consumption of electric utilities. Over the entire 1973 to 1983 period, natural gas has lost about 6% of the electric utility energy market, 8% of the industrial energy market and 5% of the residential and commercial energy market.

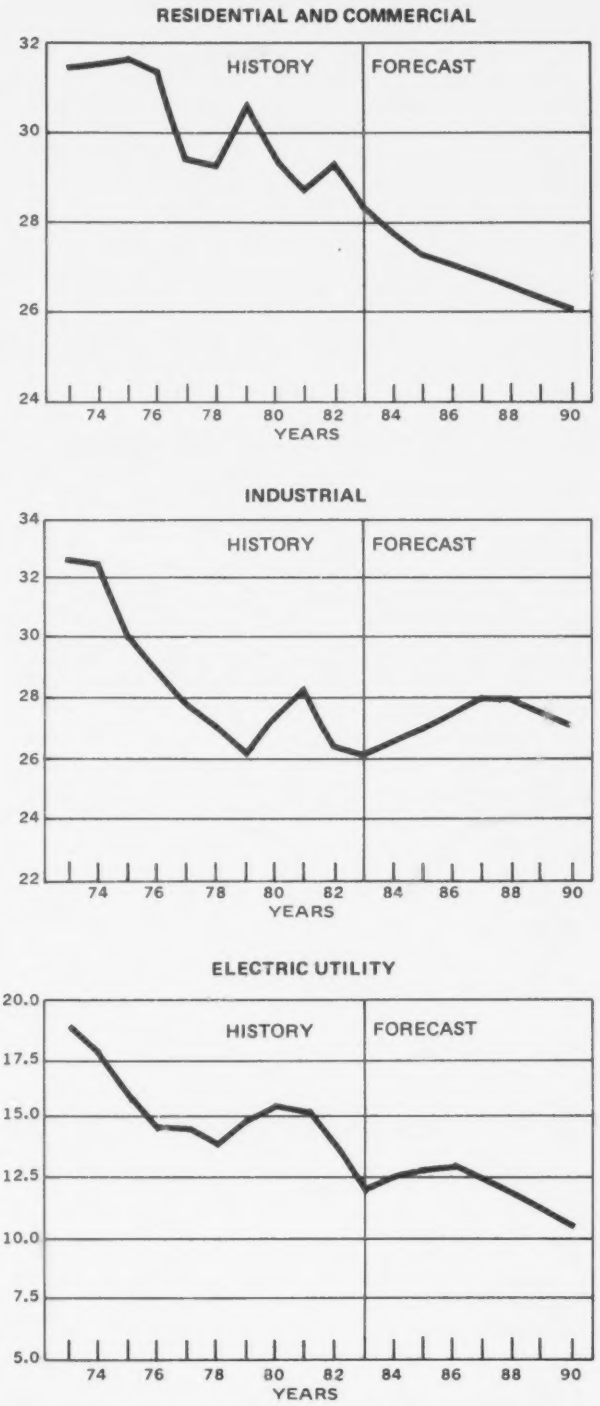
Forecasts of natural gas shares are shown in Figure 2 on the following page. The share of natural gas in all energy consumption recovers in 1984 in all markets, with the recovery in the industrial market being strongest and persisting for the longest period of time. By the late 1980's, the share again declines in all sectors, as supply conditions for alternative energy forms become more favorable relative to those for natural gas.

Should real end-user gas prices decline in 1984 and 1985, due to a greater than anticipated expansion of the competitive forces described earlier, the gas share recovery will be even greater and more rapid. Beyond 1986, however, gas shares will still decline due to the lack of availability of North American natural gas sources and the higher costs associated with LNG imports. If all structural changes now taking place are choked off, rises in real gas prices will lead to continued share erosion in all markets.

DESTRUCTION OF THE BUBBLE

Rising demand will bring rising production which will, in turn, lower the bubble. Between 1983 and 1985, production increases by 1.0 TCF, or approximately one third of the 3.0 TCF size of the amount of gas shut-in during 1983. However,

FIGURE 2
NATURAL GAS SHARE OF ENERGY MARKET
(Percent of Primary BTU)



an even greater factor in eliminating the current surplus will be a decline in the available supply of natural gas.

Two general factors will be responsible for the decline in supply, the first being declines in the level of lower–48 proven reserves. This will decline because production will exceed reserves additions through at least 1986. Our forecasts of lower–48 production and reserves are shown in Table 2. From the end of 1983 to the end of 1985, reserves decline 12.4 TCF, or about 7.5 percent. The reason for the low level

of reserve additions in 1984 and 1985 is the low level of drilling. As the market tightens, drilling picks up, so that reserve additions are 4 TCF higher in 1986 than in 1985.

TABLE 2

U.S. LOWER-48 PRODUCTION AND RESERVE RELATIONSHIPS, 1982-1986

(TCF/YR)

	Opening Reserves (Jan. 1)	Reserve Additions	Production	Closing Reserves (Dec. 31)	Net Additions
1982	169.8	18.0	18.5	169.3	−0.3
1983	169.3	13.3	16.6	166.0	−3.3
1984	166.0	11.2	17.4	159.8	−6.2
1985	159.8	11.4	17.6	153.6	−6.2
1986	153.6	15.4	17.7	151.3	−2.3

The other factors responsible for the decline in supply will be a continuation of the 1981 to 1987 decline in desired produceability (previously shown in Figure 1) for both economic and technical reasons. As expectations of near-term prices continue to fall, so will incentive for near-term production. Further, many of the fields which were subject to extremely high produceability over the 1978 to 1981 period, and which were subsequently shut in, will now be technically capable of a considerably lower rate of produceability. Several analysts have stressed that this is particularly true of fields in the Gulf of Mexico.

Our forecasts of both actual and desired production are shown below in Table 3. As shown in column (1), we expect a decline of desired produceability to 10.9% by 1985. Desired production then declines 2.1 TCF between 1983 and 1985, while, as previously mentioned, actual production increases by 1.0 TCF. The result is that the 3.0 TCF amount of shut-in gas in 1983 is eliminated in 1985. By late 1985, a tightened market will lead to increased Canadian imports and possibly to some rises in real prices, where production is equal to gross wet gas withdrawals minus amounts used for repressuring, volumes of nonhydrocarbon gases removed, and volumes vented and flared.

TABLE 3

LOWER-48 ACTUAL VERSUS DESIRED PRODUCTION, 1982-1986

	Desired Produceability (%)	Opening Reserves (TCF)	Desired Production (TCF)	Actual Production (TCF)	Difference (TCF)
1982	11.9	169.8	20.2	18.5	1.7
1983	11.6	169.3	19.6	16.6	3.0
1984	11.1	166.0	18.5	17.4	1.1
1985	10.9	159.8	17.5	17.6	−0.1
1986	10.9	153.6	16.8	17.7	−0.9

POST-1985 PRODUCTION LEVELS

By 1986, after all excess domestic natural gas production capacity is worked off, production levels begin to depend upon the level of reserve additions and hence on, wellhead prices for newly discovered gas and producer cash flow. What will happen to post-1985 wellhead prices is most difficult to forecast as they will depend upon a host of currently unresolved problems. Should wellhead prices increases about 3 to 4 percentage points more than the rate of inflation in the post-1985 period, domestic production will equal 16.8 TCF, down 0.9 TCF from 1986. Imports in 1990 will equal 2.0 TCF.

In summary, we expect that the worst is over for this industry. In particular, as long as natural gas pricing remains competitive with oil products, recovery of demand should be swift. Further, diminished prices, less drilling and technical factors will also reduce desired supply so that the bubble will be gone by mid-1985. Beyond 1985, with competitive pricing, demand should stay in balance with production.

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